ACCESSION #: 9609250125
LICENSEE EVENT REPORT (LEI)

FACILITY NAME: PILGRIM NUCLEAR POWER STATION PAGE: 1 OF 14

DOCKET NUMBER: 05000293

TITLE: Automatic Scram Resulting from load Rejection at 100
Percent Power
EVENT DATE: 08/29/94 LEI #: 94-005-01 REPORT DATE: 09/11/96

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: N POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(iv), 50.73(a)(2)(vii)(C)

LICENSEE CONTACT FOR THIS LEI:
NAME: Douglas W. Ellis, Principal Engineer TELEPHONE: (508) 830-8160

COMPONENT FAILURE DESCRIPTION:
CAUSE: X SYSTEM: TB COMPONENT: GEN MANUFACTURER: G080
X NH DMP P014
REPORTABLE NPRDS: Y
Y

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On August 29, 1994, at 0732 hours, an automatic scram occurred while at 100 percent reactor power. The scram was the result of a load rejection that was automatically initiated by a Main Generator faulted condition. Responses included automatic transfer of the plant's auxiliary power system and the brief, automatic opening of three of the Main Steam relief valves for pressure relief. The Reactor Core Isolation Cooling System was operated manually for Reactor Vessel level control for approximately three minutes. Two in-series secondary containment dampers did not fully close (i.e., approximately 90-95 percent closed) as designed but the secondary containment design basis was evaluated as being met with the dampers in the as-found position.

The cause of the main generator fault was the partial blockage of cooling water through one of the generator stator bars that was caused by foreign

material, i.e, pieces of gasket, inadvertently introduced into the main generator stator cooling water system oulet header. Corrective action taken included completely rewinding the generator stator, completely rewinding the generator rotor, and inspecting and flushing the generator stator cooling water system. The cause of the two dampers not fully closing was an accumulation of damper lubricant and dirt along the dampers' side seals and a buildup of degraded lubrication in the dampers' actuators. Corrective action taken included cleaning the dampers, modifying the preventive maintenance program to inspect the secondary containment dampers more frequently, and to periodically rebuild the dampers' actuators. The event posed no threat to public health and safety.

END OF ABSTRACT

REASON FOR THE SUPPLEMENT

This supplement is submitted to identify the root cause and related corrective actions for the main generator fault and two in-series secondary containment dampers that did not fully close. The root causes and related actions had not been finalized when the initial report was prepared.

BACKGROUND

The turbine generator is non-safety related and consists of the turbine, generator, exciter, controls, and required subsystems. The turbine utilizes mechanical hydraulic controls and required subsystems to convert steam to rotational energy. The generator rotor is directly coupled to the turbine and, in conjunction with the exciter, controls, and armature winding, converts the rotational energy to electrical energy. The generator frame and end shields are of welded gastight construction, supporting and enclosing the stationary armature winding and core, rotor (field), and coolers. The principal cooling medium is hydrogen gas that is contained within the generator frame and circulated by fans mounted at each end of the rotor. The rotor is hydrogen gas cooled. The armature winding is cooled externally by hydrogen gas and internally by stator cooling water. The armature winding is formed by insulated stator bars, assembled in slots, joined at the ends to form coils and connected in phase belts by connection rings at the end of the armature winding. The stator bars are composed of hollow insulated copper conductors (strands), arranged in the form of rectangular bars. An insulation system is applied over each stator bar. The insulation system for each bar includes several layers of mica tape bonded with a thermosetting binder.

The result is a high density, high dielectric strength system that has high tensile strength throughout the generator operating temperature range.

The individual hollow strands of each stator bar are manifolded together at each end of the bar by a clip assembly. All strands are brazed into this clip which has one tube connection to carry the combined cooling water flow of the strands. Separate brazed connections complete the electrical circuit to the next stator bar. The cooling water flow through the hollow strands is clean, low conductivity water provided by the Stator Cooling Water (SCW) subsystem. The SCW subsystem is designed to operate as a subloop in the turbine-generator control system. Provision is made for automatic regulation of temperature and flow to the stator windings and the generator excitation system rectifiers.

The SCW subsystem includes instrumentation, a storage tank, two pumps connected in parallel, two in-series coolers, filters, a demineralizer, valves, and piping to and from the generator stator windings and excitation system rectifiers. During normal operation, SCW flow to the stator windings and exciter rectifiers is drawn from the storage tank, pumped through the coolers, filtered, directed to the stator windings and rectifiers, and returned to the storage tank. A portion of the SCW flow is directed to the demineralizer for continuous purification of the SCW water.

The generator output 24 KV voltage is stepped up through the Main Transformer to 345 KV, into the switchyard ring bus and to the New England power grid via transmission lines 342 and 355. The generator voltage is also reduced through the Unit Auxiliary Transformer (UAT) to 4,160 VAC and into the plant Auxiliary Power Distribution System (APDS). Located at the end of this report is a simplified single line drawing that includes the Main Generator, Main Transformer, UAT, Startup Transformer (SUT), and switchyard.

On August 28, 1994, at approximately 1048 hours, ACB-103 and ACB-104 were opened for planned switchyard betterment/maintenance to insulators in the related section of the switchyard. Next, the mechanical disconnects of these ACBs were opened and line 342 was de-energized. ACB-103 and ACB-104 were subsequently reclosed. At 2126 hours, ACB-103 and ACB-104 were opened as part of preparations for returning the switchyard to normal. At 2139 hours, ACB-104 self-closed (with its mechanical disconnects still open). Subsequent investigation revealed smoke coming from the ACB-104 control cabinet (located in the switchyard). Control power to ACB-104 was removed. At 2346 hours, ACB-103 was closed.

ACB-104 was opened manually at 0005 hours on August 29, 1994.

At 0705 hours, a generator hydrogen system trouble alarm (Panel C3R window D-3) occurred. Operator response to the alarm included checking the Panel C100 status and alarm. The operator who responded to the alarm reported the generator core monitor alarm at C100 had been indicated, the core monitor recorder at Panel C100 indicated a normal reading of approximately 89 percent, and the Panel C100 alarm was reset. The Panel C3R alarm D-3 was then reset.

The SCW system water conductivity was reported increasing and operators also investigated the reported condition.

At 0710 hours, a generator field ground alarm (Panel C3R window E-1) occurred. Electrical maintenance personnel were notified and ground readings were subsequently taken. The readings indicated a current of 1300 micro amperes (the alarm setpoint is approximately 150 micro amperes) that was reported after the event.

At 0712 hours, a generator cooling water trouble alarm (C3R window D-1) occurred. Operator response to the alarm included checking the Panel C100 status and alarm. At 0715 hours, the operator who responded to the alarm reported no panel C100 alarm indication but the alarm condition would not clear.

At 0725 hours, and with the conductivity reportedly increasing, actions were initiated to isolate the SCW demineralizer and control room personnel were briefed on a possible turbine trip, reactor scram and actions to be taken.

Just prior to the event, plant operating conditions included the following:

o The reactor mode selector switch was in the RUN position. The reactor was at 100 percent power. The Reactor Vessel (RV) pressure was 1035 psig with the RV water temperature at approximately 550 Degrees F. The RV water level was approximately +27 inches.

o The Recirculation System motor-generator sets/pumps 'A' and 'B' were in service with each loop in the local manual control mode. The Condensate System and Feedwater System pumps were all in service. The Feedwater Level Control System was in the three element control mode.

o The 345KV transmission lines 342 and 355 were energized. ACB-104 was out of service in the open position with its control circuit de-energized and mechanical disconnects open. ACBs -102, -103 and -105 were closed. The 4160 VAC APDS was energized from the UAT with the bus transfer switches in the ON position. The Shutdown Transformer was in standby service with the 23 KV distribution system energized.

o The Emergency Diesel Generator (EDG) 'A' and EDG 'B' were in standby service.

EVENT DESCRIPTION

On August 29, 1994, at 0732 hours, an automatic Reactor Protection System (RPS) scram signal and scram occurred while at 100 percent reactor power. The scram occurred as a result of a load rejection. The event was initiated when the Main Generator ground protection relay 259 actuated the generator lockout relay 286-1, related auxiliary relays and turbine Master Trip Solenoid (MTS-1).

The actuation of the lockout relay 286-1 included the opening of ACB-105, the generator field breaker, and automatic transfer of the source of power for the APDS from the UAT to the SUT. The opening of the field breaker and/or ACB-105, with ACB-104 open, resulted in a momentary mismatch between Generator load and Turbine power. The mismatch resulted in an acceleration of the Turbine-Generator.

The trip of MTS-1 included the following responses:

o Loss of oil pressure to pressure switches (PS-37/38/39/40) that resulted in the RPS scram signal that initiated the scram.

o Automatic closing of the Turbine Control Valves, Stop Valves, and Combined Intermediate Valves. The Main Steam/RV pressure rapidly increased because the steam flow exceeded the 25% total bypass capability of the Turbine Bypass Valves. The pressure rapidly increased to approximately 1125 psig.

The pressure increase also caused the Target Rock two-stage Main Steam relief valves RV-203-313 (pilot s/n 1048)/3C (pilot s/n 1046)/3A (pilot s/n 1040) to lift for pressure relief. The relief valves were each open for approximately 10 seconds. The maximum steam pressure occurred approximately 2.0 seconds after the first relief valve opened.

o Trip of the turbine lockout relay 286-2.

Meanwhile, the RV water level decreased to approximately -8 inches due to the decrease in the void fraction in the RV water. The decrease to below the low RV water level setpoints (calibrated at approximately +12 inches) resulted in the automatic initiation of the Primary Containment Isolation Control System (PCIS) and Reactor Building Isolation Control System (RBIS).

The PCIS actuation resulted in the following designed responses:

o Automatic closing of the inboard and outboard Primary Containment System (PCS)/Reactor Water Sample isolation valves AO-220-44 and -45.

o Automatic closing of the inboard and outboard PCS Group 2/sample system isolation valves that were open.

o The PCS Group 3/Residual Heat Removal (RHR) System Shutdown Cooling suction piping isolation valves MO-1001-47 and -50 remained closed.

o The PCS Group 3/RHR System Low Pressure Coolant Injection mode valves MO-1001-29A/B remained closed.

o The PCS Group 6/Reactor Water Cleanup (RWCU) System isolation valves closed automatically.

The RBIS actuation resulted in the automatic start of the Standby Gas Treatment System (SGTS) Trains 'A' and 'B' and automatic closing of the Reactor Building/Secondary Containment System (SCS) Trains 'A' and 'B' supply and exhaust ventilation dampers except for the in-series supply dampers AON-80 and AON-81.

Initial Control Room operator response was orderly and included the following. The reactor mode selector switch was moved to the REFUEL position in accordance with procedure 2.1.6, "Reactor Scram". EOP-01, "RPV Control", was entered because the RV water level was less than +9 inches. The verification of the insertion of all control rods was initiated and completed promptly after the scram.

The Main Control Room Panel C7 control switches of dampers AON-80 and AON-81 were manipulated to close the dampers. The indicated position of AON-80 and AON-81 continued to indicate a dual position.

Two feedwater pumps ('A' and 'B') were moved from service in accordance with procedure 2.1.6. The Recirculation System motor-generator (MG) sets/pumps 'A' and 'B' automatically ran back to approximately 6065 percent speed. The reduction in feedwater flow resulted in an automatic recirculation MG sets/pumps 'A' and 'B' runback signal (to approximately 20 percent speed) while the speed was being manually reduced by a Licensed Operator at the Control Room Panel C904 controls.

At 0740 hours, feedwater pump 'A' was started and feedwater pump 'C' was removed from service due to a pump seal leak.

The RV water level was restored to the normal operating band (+20" to +30") by 0742 hours.

Procedure 2.1.7 (rev. 30), "Vessel Heatup, and Cooldown", was initiated at 0747 hours.

At 0811 hours, dampers AON-80 and AON-81 were fully closed manually and tagged.

EOP-04, "Secondary Containment Control", was entered at 0820 hours due to the Main Steam tunnel temperature (131 Degrees F). This temperature was due to the RBIS isolation that affects the normal Reactor Building ventilation including the Main Steam tunnel. Radiation Protection personnel were notified to initiate a radiation survey in the Reactor Building in accordance with EOP-04. The survey was completed with satisfactory results.

The RBIS and Group 2 portion of the PCIS were reset at 0822 hours. The Reactor Building Ventilation System and SGTS were subsequently returned to normal service except for dampers AON-80 and AON-81 that were left closed and tagged.

At 0838 hours, feedwater pump 'A' was removed from service due to an oil leak from its auxiliary oil pump. Feedwater pump 'B' failed to start when a start was attempted. Subsequently investigation revealed feedwater pump 'B' failed to start because the pump's auxiliary oil pump breaker had tripped due to a thermal overload.

At 0840 hours, the Reactor Core Isolation Cooling (RCIC) System was manually started in the injection mode for RV level control. This action was taken in accordance with the guidance of EOP-01.

After resetting the auxiliary oil pump breaker, feedwater pump 'B' was started and the RCIC System was returned to standby service at 0843 hours with RV water level at approximately +30 inches.

The RWCU/Group 6 portion of the PCIS was reset at 0911 hours and the RWCU System was returned to service at 0915 hours.

The reactor mode selection switch was moved from the REFUEL position to the SHUTDOWN position at 0938 hours. This action resulted in an expected RPS scram signal. The control rods remained inserted.

At 0940 hours, the RPS was reset.

At 0958 hours, EOP-01 was terminated.

After preparations that included flushing of applicable piping, the RHR System Loop 'A' was started in the shutdown cooling (SDC) mode at 2033 hours.

The reactor was in a cold shutdown condition with the RV head vent valves open by 0700 hours on August 30, 1994.

Problem Report (PR) 94.9358 was written to document the scram and indicated positions of dampers AON-80 and AON-81. The NRC Operations Center was notified in accordance with 10 CFR 50.72 it 0944 hours on August 29, 1994. Several other Problem Reports were written to document other aspects or observations related to the events.

A post trip review of the event was initiated in accordance with procedure 1.3.37 (Rev. 9), "Post Trip Reviews". The event was classified as a type requiring investigation and corrective action prior to plant restart. A Multi-Discipline Analysis Team (MDAT) was formed to investigate the root cause of the noted events.

A critique was held on August 29, 1994. The critique was attended by appropriate personnel including licensed operators on shift at the time of the event.

CAUSE

The cause of the load rejection and subsequent scram was a faulted condition sensed by the Main Generator ground protection relay 259. The relay was initiated by a Main Generator fault.

The cause of the main generator fault was the partial restriction of stator cooling water system flow through two of the main generator stator bars. The restriction reduced the flow of cooling water through the stator bars and, consequently, caused localized overheating and mechanical failure of stator bars bottom 17 (B-17) and top 31 (T-31) which are hydraulically and electrically connected. The root cause of the stator bar failure was the introduction of foreign (gasket) material into the stator cooling water outlet header. Forensic examination found a piece of light blue gasket material in the stator cooling water exit tube of stator bar B-17. An imprint on the gasket material matched the flow exit area such that the piece of gasket material may have been covering 80 percent of the flow exit area of the outlet water (stator cooling) box of stator bar B-17. This flow restriction led to the overheating and resultant failure of stator bars B-17 and T-31 that caused the main generator fault.

The pieces of gasket material found in the outlet tube of stator bar B-17 were relatively large, i.e., 3/4 inch or greater. The size and location (outlet header) implies the introduction of the gasket material during a period when the stator cooling water outlet flange was disconnected. While it was not possible to determine exactly when the material was introduced or how much material was introduced, some reasonable conclusions may be drawn based on system design. The introduction of a complete gasket can be ruled out because of its size, which is larger than the opening, and its stiffness. Therefore, a conclusion can be made that one or more pieces of the gasket material were inadvertently introduced during a maintenance activity that required the gasket to be replaced. This activity may have required the gasket to be removed in pieces, providing the opportunity for its introduction into the outlet header of the main generator stator cooling water system. The main generator was manufactured in 1968 by the General Electric Company. Generator data includes: serial number 180X341, four pole, 1800 rpm, Wrobel stator strand transposition (180 Degrees per pass), and a strand configuration of 4 columns by 14 rows.

The cause of dampers AON-80 and AON-81 not fully closing was the combined effects of an accumulation of damper lubricant and dirt along the dampers' stainless steel side seals and a buildup of degraded lubrication in the dampers' actuators. The accumulation of dirt resulted in a relatively rougher surface along the side seals and increased the friction forces that retarded the closing action of the dampers' actuator on August 29, 1994. The cause of the accumulation of dirt was the preventive maintenance program frequency (once per year) for inspection of the secondary containment dampers. The cause of the buildup of degraded lubrication in the dampers' actuators was a lack of preventive maintenance in that the actuators were not included in the preventive maintenance program and, consequently, had not been rebuilt since installation as part of the replacement of the secondary containment dampers in the 1986-1988 time frame. On March 27, 1995, while shut down and after corrective action taken for PR 94.9358 in 1994, damper AON-81 did not completely close. The problem was documented in PR 95.9140. The root cause conducted for PR 95.9140 concluded damper AON-81 did not completely close because the dampers actuator was in need of cleaning and the damper actuator piston did not move readily in the actuator cylinder. The degradation of the lubrication in the actuator affected the closing torque of the actuator. The dampers were manufactured by the Pacific Air Products Company, model SL100-ML. The actuators of dampers AON-80 and AON-81 were manufactured by the Bettis Corporation, model NCB-415SR60.

The cause of ACB-104 self-closing on August 28, 1994, was fire damaged cables in its control cabinet (located in the switchyard). The cause of the fire appears to have been the breakdown of insulation in an ACB-104 control cable. The insulation breakdown was located where the insulation came in contact with a protruding tap of a wire wound power resistor in the control cabinet. The insulation breakdown is believed to be the result of the accumulated effects of 25 years of deterioration due to water intrusion, the contact with the resistor and intermittent heat generated by the resistor.

CORRECTIVE ACTION

Corrective actions taken related to the main generator fault included the following:

o The main generator stator was completely rewound.

o The main generator stator cooling water system was inspected and flushed with satisfactory results.

o The main generator rotor (field) was completely rewound.

Corrective actions taken related to dampers AON-80 and AON-81 included the following:

o Dampers AON-80 and AON-81 were cleaned in accordance with procedure 8.7.3.1 (Rev. 8), "Inspection of Secondary Containment Dampers," and detailed directions in the dampers' vendor manual. The dampers were then operated several times with satisfactory results, i.e., complete closure. The other secondary containment dampers were cleaned and subsequently operated with satisfactory results.

o The preventive maintenance program was modified to more frequently (every 6 months) inspect the secondary containment dampers, and added a periodic (every 4 years) rebuild of the actuators of the secondary containment dampers beginning in 1995. These frequencies may be modified based on experience.

o The actuators of all secondary containment dampers were rebuilt in the 1995 refueling outage (RFO-10).

These actions resulted from PR 94.9358.

Corrective actions related to ACB-104 were previously identified in that the replacement of ACB-104 (and its control cabinet) were planned for the 1994 mid cycle outage. The control panels of the other ACBs were visually inspected and thermographically scanned with satisfactory results. ACB-104 and its control cabinet was replaced while shut down. The replacement of the other ACBs (and control cabinets) was previously scheduled as part of the switchyard betterment project, and the ACBs have been replaced.

PREVENTIVE ACTION

Preventive action taken related to the main generator fault included the following:

o Controls for precluding the introduction of foreign material into the main generator and stator cooling water system were implemented during the main generator outage.

o Procedure 1.5.19 (rev. 0), "Foreign Material Exclusion for Main Turbine, Main Steam Valves, and Moisture Separators," was issued. Essentially, the procedure formally establishes work standards and guidelines to maintain the cleanliness of systems and equipment including the nonsafety-related turbine-generator.

o A new generator data system was installed via an engineering modification document (PDC 94-39). The system monitors the metal temperature of the generator stator bars, generator stator cooling water outlets, and the generator hydrogen coolers. The system provides data to a data acquisition and monitoring computer that is available to operators in the main control room.

OTHER ACTION

Procedure 8.7.3.1 was revised (to rev. 9) and approved on November 1,

1994. The revision, an enhancement, included clarifying information from the dampers' vendor manual recommendations regarding the method of cleaning damper blades and seals. This action resulted from PR 94.9358.

Temporary procedure (TP) 94-085 (rev. 0), "Generator Startup and Postwork Testing," was issued, effective November 29, 1994. The procedure provided instructions including those for monitoring generator stator bar temperatures and stator cooling water outlet slot temperatures during startup and power ascension. The procedure also provided administrative guidance during power ascension to collect data and perform surveillances to support post work testing of the generator, turbine valves, and turbine controls.

Reactor startup occurred on November 29, 1994, at 0657 hours, and the generator was phased to the 345 KV transmission system on November 30, 1994, at 1519 hours.

SAFETY CONSEQUENCES

The event posed no threat to public health and safety.

The load rejection experienced during this event is bounded by the transient analysis described in the Updated Final Safety Analysis Report section 14.4.3, "Generator Load Rejection Without Bypass." The opening of some or all of the main Steam two-stage relief valves is an expected response to a load rejection with or without bypass at greater than 45 percent power. For this event, relief valves RV-203-3A/B/C opened. Relief valve RV-203-3D (pilot s/n 1208) did not lift because RV-203-3A/B/C lifted and curtailed the RV/Main Steam pressure increase before RV-203-3D lifted. The Technical Specification 3.6.D.1 setting for the Main Steam System/Pressure Relief System (PRS) relief valves is 1095 to 1115 psig with a tolerance of +/- 11 psi. The nameplate setpoint of the relief valves is 1115 psig. Therefore, the setpoint range of the relief valves including tolerance is 1004 psig to 1126 psig. During the event, the highest RV dome pressure that occurred was approximately 1125 psig.

The Technical Specification 3.6.D.1 setting for the Main Steam/PRS safety valves is 1240 +/- 13 psi. During the event, the highest RV pressure that occurred was approximately 115 psig less than the safety valves' setpoint of 1240 psig.

The scram signal was the designed response to a load rejection with the Turbine first stage pressure at approximately 725 psig which was greater than the scram bypass setpoint (calibrated at 108 psig +/- 3 psig increasing) corresponding to 25 percent of the normal first stage pressure. The maximum turbine speed that occurred was approximately 1900 RPM and was less than the speed corresponding to the 109% overspeed trip setting of 1972-1998 RPM and the 112% backup overspeed trip setting of approximately 2016 RPM.

The decrease in the RV water level was the expected response to the scram and accompanying shrink in the RV water. The PCIS and RBIS actuations were the expected designed responses to a low RV water level condition (i.e., less than approximately +12 inches).

The Technical Specification Table 3.2.13 trip setting for actuation of the Core Standby Cooling Systems (CSCS) is -46.3 inches. During the event, the lowest RV water level that occurred (-8 inches) was approximately 38 inches above the CSCS setpoint. In addition, the level was approximately 119.5 inches above the level that corresponds to the top of the active fuel zone.

The CSCS consists of the HPCI System, Automatic Depressurization System (ADS), Core Spray System, and RHR/LPCI mode. Although not part of the CSCS, the RCIC System is capable of providing water to the RV for high pressure core cooling, similar to the HPCI System. The ADS is a backup to the HPCI System and functions to reduce RV pressure to enable low pressure core cooling provided independently by the Core Spray System and the RHR/LPCI mode. The CSCS and RCIC System were operable.

The lowest RV water level that occurred was greater than the setpoint (calibrated at approximately -46.3 inches) that initiates the ATWS System functions for a Recirculation Pump Trip (RPT) and Alternate Rod Insertion (ARI). The highest RV pressure that occurred was less than the setpoint (calibrated at approximately 1175 psig) that initiates the ATWS System RPT and ARI trip functions and the setpoint (calibrated at approximately 1400 psig) that initiates the ATWS System function for a Feedpump Trip.

The highest RV water level that occurred was approximately +35 inches. The level was less than the level (approximately 112 inches) of the bottom of the Main Steam piping.

The highest Suppression Pool bulk water temperature that occurred was approximately 74 Degrees F. The temperature was less than the maximum water temperature (120 Degrees F) specified by Technical Specification 3.7.A.1.h during RV isolation conditions.

Technical Specification 3.7.A.1.m specified the Suppression Pool/Chamber be maintained between -6 to -3 inches which corresponds to a downcomer submergence of 3.00 and 3.25 feet, respectively. The highest Suppression Pool water level that occurred was approximately -4 inches (129 inches on LI/LR-1001-604A). The level was less than the level corresponding to the maximum Suppression Pool volume of 94,000 cubic feet specified by Technical Specification 3.7.A.1.b. A Suppression Pool volume of 94,200 cubic feet corresponds to a level of +6 inches (LR-5038/5049) or 139 inches (LI-1001-604A/B). The level was less than the settings of level switches LS-2351A/B that control the Suppression Pool/HPCI pump suction valves.

The design basis of the secondary containment system (SCS), to be sufficiently leak tight to allow the SGTS to reduce the Reactor Building pressure to a minimum subatmosphere pressure of 0.25" water, was evaluated relative to the as-found position of dampers AON-80 and AON-81. The evaluation was conducted because no direct observation of the building subatmospheric pressure was noted during the period the SGTS was in service while dampers AON-80 and AON-81 were not fully closed. The evaluation concluded the SCS design basis was met with the dampers in the as-found position.

This report is submitted in accordance with 10 CFR 50.73 subpart (a)(2)(iv) because the actuation of the RPS, although an expected designed response to the load rejection at 100 percent reactor power, was not planned. This report is also submitted in accordance with subpart (a)(2)(vii)(C) because the in-series dampers AON-80 and AON-81 did not fully close automatically.

SIMILARITY TO PREVIOUS EVENTS

A review was conducted of Pilgrim Station LERs submitted since January 1984. The review focused on LERs submitted in accordance with 10 CFR 50.73(a)(2)(iv) that involved a load rejection or similar scram. The review identified load rejection scrams reported in LERs 50-293/85-025-00, 90-008-00, 92-016-00, and 93-004-00. None involved a generator fault condition. A review was also conducted of occurrence reports/LERs submitted prior to 1984. The review focused on reports that involved a load rejection or similar scram. The review identified load rejection scrams reported in LERs 77-020, 78-003, 78-035, 78-048, 79-027 and 83-007. None involved a generator fault condition.

A review was also conducted of Pilgrim Station LERs submitted since 1984 that involved secondary containment dampers. The review identified that the secondary containment dampers were replaced during the 1986-1988 outage. The review also identified an event reported in LER 93-026-00 that included the SCS ventilation supply damper AON-79, in-series with damper AON-78, that did not fully close as a result of a RBIS isolation signal that occurred while in a hot shutdown condition on November 8, 1993. The in-series damper, AON-78, closed automatically. Investigation revealed a dirt buildup had prevented damper AON-79 from closing fully. Damper AON-79 was cleaned, tested with satisfactory results and returned to service on November 8, 1993.

ENERGY INDUSTRY IDENTIFICATION SYSTEM (EIIS) CODES

The EIIS codes for this report are as follows:

COMPONENTS CODES

circuit breaker, ac (ACB-104) 54
damper (AON-80/AON-81) DMP
generator, turbine TG
pump P
relay, locking-out (286-1, 286-2) 86
relay (259) RLY
rheostate (register RB) 70
valve relief (RV-203-3A/B/C) RV

SYSTEMS

containment isolation control system (PCIS, RBIS) JM
engineered safety features actuation system JE
(PCIS, RBIS, RPS)
feedwater system SJ
main generator system TB
main steam system SB
main turbine system TA
medium-voltage power system (601 V-35 KV) EA
plant protection system (RPS) JC
reactor containment building NH
reactor core isolation cooling (RCIC) system BN
reactor recirculation system AD
reactor water cleanup (RWCU) system CE
residual heat removal system (SDC mode) BO
standby gas treatment system (SGTS) BH
switchyard system (345 KV) FK

TEXT PAGE 14 OF 14

Figure omitted.

ATTACHMENT TO 9609250125 PAGE 1 OF 1

Boston Edison 10 CFR 50.73

Pilgrim Nuclear Power Station
Rocky Hill Road
Plymouth, Massachusetts 02360

E. T. Boulette, PhD
Senior Vice President--Nuclear

September 11, 1996
BECo Ltr. #96-082

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D.C. 20555

Docket No. 50-293
License No. DPR-35

The enclosed supplemental Licensee Event Report (LER) 94-005-01, "Automatic Scram Resulting from Load Rejection at 100 Percent Power," is submitted in accordance with 10 CFR Part 50.73.

Please do not hesitate to contact me if there are any questions regarding this report.

E.T. Boulette, PhD
DWE/dmc/9400501

cc: Mr. Hubert J. Miller
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Sr. NRC Resident Inspector - Pilgrim Station

Standard BECo LER Distribution

*** END OF DOCUMENT ***